BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769. And Related Matters.	Rulemaking 14-08-013 (Filed August 14, 2014) Application 15-07-002 Application 15-07-003 Application 15-07-006

(Not Consolidated)

In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resources Plan Pursuant to Public Utilities Code Section 769. And Related Matters.	Application 15-07-005 (Filed July 1, 2015) Application 15-07-007 Application 15-07-008

COMMENTS OF THE OFFICE OF RATEPAYER ADVOCATES ON THE JOINT ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE'S (ALJ) RULING REGARDING TRACK 2 DEMONSTRATION PROJECTS, THE EMAIL RULING EXTENDING DEADLINE FOR TRACK 2 COMMENTS AND THE ALJ'S RULING REGARDING COMMENTS ON TRACK 2 DEMONSTRATION PROJECTS

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Attachment 6 – Excerpts from CPUC Resolution E-4317, approving California Solar Initiative (CSI) Research, Development, Deployment and Demonstration (RD&D) Program's Solicitation #1

I. INTRODUCTION

Pursuant to the Joint Assigned Commissioner and Administrative Law Judge (ALJ) Ruling on May 17, 2016 (May 17 Joint Ruling),[1] the ALJ Ruling on July 6, 2016 (July 6 Ruling)[2] and ALJ Ruling on July 12, 2016 (July 12 Ruling),[3] the Office of Ratepayer Advocates (ORA) submits these comments on the revised Investor-Owned Utilities (IOU) and new non-IOU proposals for Demonstration Projects (Demos) C, D and E. Demos C, D and E are proposed in compliance with Commission Guidance issued February 6, 2016.[4] The IOUs first proposed Demos C, D and E in their July 1, 2015 Distribution Resources Plan (DRP) Applications.[5]

ORA files these comments pursuant to its statutory mission to obtain the lowest possible utility rates consistent with reliable and safe service levels. These comments are timely filed in compliance with the July 6 Ruling, which extended the comment deadline from July 13, 2016 to July 22, 2016.

ORA appreciates the opportunity to comment on IOU and non-IOU proposals for Demos C, D and E. ORA also appreciates the California Public Utilities Commission (CPUC) Energy Division's (ED) efforts in facilitating a workshop on Demos C, D and E on June 28, 2016, allowing parties the opportunity to pose questions on demonstration projects and inviting ORA to participate in a panel discussion. ORA looks forward to working with the IOUs, CPUC staff and other parties to cost-effectively integrate distributed energy resources according to Public Utilities (P. U.) Code Section 769.

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[1] Joint Assigned Commissioner and Administrative Law Judge's Ruling Regarding Track 2 Demonstration Projects, May 17, 2016.

[2] Email Ruling Extending Deadline for Track 2 Comments, July 6, 2016.

[3] ALJ's Ruling Regarding Comments on Track 2 Demonstration Projects, July 12, 2016.

[4] Assigned Commissioner's Ruling On Guidance For Public Utilities Code Section 769 – Distribution Resource Planning, R. 14-08-013, February 6, 2015.

[5] Application of San Diego Gas and Electric Company (U 902 E) for Approval of Distribution Resources Plan (July 1, 2015), pp. 69-88; Application of Pacific Gas and Electric Company Electric Distribution Plan (July 2015), pp. 135-157; Application of Southern California Edison Company (U 338-E) for Approval of Its Distribution Resources Plan (July 1, 2015), pp. 97-111.

In consideration of the Commission's authority to "modify any plan as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources,"[6] ORA's general recommendations on Demos C, D and E include the following:

- All Demos should include price caps for unknown DER procurement costs to mitigate potential ratepayer impact as condition of Commission approval.
- All projects previously funded through a General Rate Case (GRC), Research Development and Demonstration (RD&D) or other funding sources should account for this funding in project cost authorization to avoid any potential for the ratepayer to pay more than once for the same project.
- All Request for Offers (RFOs) for Demos C, D and E conducted to procure DER for Demos should utilize the Commission-Approved IDER Competitive Solicitation Framework, if available.
- IOUs should be open to DER procurement methods outside of RFOs, such as modification of existing programs or incentives, where it minimizes the Demo deployment timeframe or decreases ratepayer cost.

ORA also recommends the following for specific Demo projects, as follows:

<u>Demo C: Demonstrate DER Locational Benefits</u>

- Demo C projects should test the ability of DERs to provide locational benefit by calculating Locational Net Benefit Analysis (LNBA) values at the Distribution Planning Area (DPA) prior to DER procurement and deployment of Demo C, preferably co-locating Demo B and C, or calculating the LNBA at the site as a supplemental activity.
- Demo C evaluation metrics should measure the ability of the DER to achieve locational benefits calculated in the LNBA as a measure of project success, with lessons learned incorporated into successive iterations of the LNBA methodology. Only achieving distribution asset deferral through DER deployment does not achieve Demo C project goals.

<u>Demo D: Demonstrate Distribution Operations at High Penetrations of DERs</u>

[6] P.U. Code Section 769 (c).

- All Demo D projects should be reviewed for incremental learnings to existing RD&D project objectives to avoid project duplication. Utilities should update their proposals so parties can independently verify whether these projects provide incremental benefits compared to related programs.
- Demo D projects should incorporate adequate baseline readings to capture the incremental locational benefit provided by DER deployment.
- The CPUC should clarify its direction to "provide analysis of potential benefits and locational values associated with high-DER penetration" and how this differs from the requirements of Demonstration C projects.

Demo E: Demonstrate DER Dispatch to Meet Reliability Needs

- All Demo E projects should be reviewed for incremental learnings to existing RD&D project objectives to avoid project duplication. Utilities should update their proposals so parties can independently verify whether these projects provide incremental benefits compared to related programs.
- Demo E project locations should meet a customer need for increased reliability and resiliency.
- Demo E projects should address the issue of scalability by explaining how projects address barriers to microgrid commercialization identified in the recent California Energy Commission (CEC) microgrid roadmap.

Individual Demo projects are discussed in detail below. Section II.A discusses ORA's recommendations for Demo C. Individual Demo D is discussed in Section II.B. Demo D and E projects are discussed in Section II. D and II. E, respectively.

In response to the Joint Assigned Commissioner and ALJ's July 12 Ruling request to "address whether any of the Demonstration Projects could or should be combined,"[7] ORA recommends expediting consideration of Demo C and combining Demo D and E for subsequent consideration, as discussed in detail in Section F of these comments. ORA also reserves the opportunity to request evidentiary hearings in reply comments due July 29, 2016.[8]

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[7] July 12 Ruling, p. 2.

[8] "Any request for evidentiary hearings may be made in the Reply Comments due on July 29, 2016, and consistent with the ACR, must explain why hearings are needed and identify the specific material issues of fact that would be addressed." July 12 Ruling, p. 3.

II. DISCUSSION

A. General Comments Related to Demo projects

1. ORA recommends the Commission set a cost cap for demonstration projects with unknown DER procurement costs.

The IOUs quantified and seek recovery for administrative costs associated with their Demo projects' administration, verification and reporting. However, the IOUs generally did not quantify procurement costs associated with their proposed Demos. The reasonableness of DER procurement costs is a question of fact which the Commission should address as a matter of project scope prior to Demo project authorization.

Failure to set a cost cap unduly subjects ratepayers to the potential for excessive costs and is inconsistent with Commission procurement authorizations generally. For example, in the Long-Term Procurement Planning proceeding, costs are mitigated through authorization of a range of total megawatts (MW) procured.[9] Similarly, ratepayer impact is mitigated for procurement of storage under the 1.325 Gigawatt (GW) storage mandate.[10] In the case of distribution deferral and DER optimization projects, mitigating ratepayer cost impact is more complicated than merely capping the amount of MWs procured, since DER procurement also requires additional remote sensing and control equipment, and the associated costs, which may be significant. Therefore, ORA recommends the Commission evaluate the reasonableness of any cost cap as a function of the total value of the Demo project, such as the relative value of the distribution deferral plus incidental costs and some reasonable contingency margin prior to approval of any Demo C project.

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[9] *See generally* D.14-03-004, p. 143, (authorizing a range of procurement in MW).

[10] *See* D.13-10-040.

2. Project funding already authorized through the GRC or other RD&D projects should be fully accounted for to avoid ratepayers potentially paying more than once for infrastructure and other costs associated with the DRP.

The IOUs request funding for cost recovery potentially authorized in the GRC or through other RD&D projects. For example, the current Demo C proposals include a $950,000 cost associated with the administration of the solicitation itself.[11] However, the IOUs already recover administrative costs associated with procurement through the GRC. Similarly, traditional distribution grid upgrade cost recovery is also authorized in the GRC. Since many Demos include distribution deferral aspects, failure to account for the costs already authorized in the GRC present the possibility of recovering costs more than once for the same activities. It is a question of fact whether the administrative costs requested by IOUs are already accounted for in the GRC or other funding mechanisms.

According to the DRP Scoping Memo, examining the relationship between the DRP and the utilities' GRCs is deferred to Track 3 of the DRP proceeding, which has not yet started.[12] However, to avoid the possibility of ratepayers paying more than once, GRC coordination must be addressed as part of Demo C, D and E authorization to protect ratepayers from double payment in the GRC as well as through this Commission's Demo authorization.

3. ORA recommends that the IOUs utilize the IDER solicitation framework, if available.

The IOUs state a preference for testing solicitation methods for procuring DER as part of Demo projects. However, the timing of a working group report on the competitive solicitation framework working group, expected to be released August 1, 2016, and approved by the Commission this fall suggests that a Commission decision on the IDER competitive solicitation framework may line up with the timing of the

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[11] PG&E Track 2 Demo Project Proposal, p. A - 9-10.

[12] DRP Scoping Memo, p. 12.

implementation of the Demo project. ORA recommends that if the IOUs pursue DER procurement for Demo plan implementation, they utilize the Commission's IDER solicitation framework, if available. This allows the IOUs to test the IDER solicitation framework and identify any necessary modifications prior to general deployment in the distribution planning process.

Further, testing the IDER competitive solicitation framework does not preclude the IOUs from conducting solicitations for distribution deferral. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) all have previously held RFOs regarding DER deployment in their territories.

In 2014, PG&E issued a Solicitation Protocol Energy Storage Request for Offer (ES RFO) to achieve its megawatt procurement targets as part of Decision (D.) 13-10-040.[13] PG&E had a 2014 Procurement Target of 74 MW of DER in order to meet the objectives of optimization of the grid, including deferment of transmission and distribution upgrade investments, and the integration of renewable energy to the grid.[14] In the ES RFO, PG&E detailed a comprehensive list of the requirements for the type of deferral required for specific locations.[15] Therefore, PG&E already had the opportunity to test its existing procurement framework for DER deferral.

Similarly, in early 2016, SCE conducted a RFO for DER in their Preferred Resources Pilot (PRP) area.[16] The PRP was created to allow SCE to investigate how preferred resources could meet local needs at the distribution level. Furthermore, this

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[13] PG&E Energy Storage Request for Offers Solicitation Protocol, 2014 Energy Storage Request for Offers (2014 ES RFO), December 1, 2014, p. 5; Energy Storage RFO, Energy Storage Systems for Distribution Substation Investment Deferral, *available at* http://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/Energy_Storage/Information_DistributionDeferralESS.pdf.

[14] *Id.,* p. 12.

[15] *Id.* p. 15.

[16] SCE Request for Offers for Preferred Resources in SCE's Preferred Resources Pilot Area ("PRP

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RFO intended to reduce load and be dispatchable on specific circuits on a specific time frame, much like the current Demo C.

Finally, in 2014, SDG&E conducted its own solicitation for an energy storage project through a Storage Request for Proposal (RFP) requesting 4 MW of distribution-connected storage to determine if a small energy storage project could mitigate forecasted overloads and delay the need to construct a new substation.[17] After conducting the RFP, SDG&E determined that none of the 36 solicited bids were cost effective enough to reasonably select the non-wires solution to defer the construction of the new substation.[18] However, the RFP was effective in terms of obtaining bids. Therefore, testing SDG&E's procurement framework for DER deferral is not a new objective.

4. In addition to competitive procurement mechanisms, the IOUs should also consider other procurement mechanisms for Demos.

The current timeline for an RFO process, from initial request to project implementation, is roughly three years. For example, the 2014 PG&E ES RFO was released on December 1, 2014. The guaranteed commercial operating date for deferral projects went as far as May 1, 2018, which is a 3.5 year lead time until project operation.[19] The current Demo C projects all have a similar lead time to implementation. For example, PG&E's timeframe for Demo C's completion, including data gathering and final report, suggests a 3.5 year timeframe as well.[20]

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FRO 2"), PRP RFO 2 Participant Instructions – Version 3, January 22, 2016, p. 1.

[17] SDG&E's 2014 Energy Storage Distribution Reliability / Power Quality Request for Proposal Seeking a 4 MW Energy Storage System, Post Solicitation Report, December 1, 2015, p. 8.

[18] *Id.*, p. 16.

[19] PG&E ES RFO, p. 15.

[20] PG&E Track 2 Demo Project Proposal, p. A – 9-10.

Therefore, ORA recommends that the IOUs also explore other procurement mechanisms such as adjusting incentives in existing programs, such as IOU-run demand response or energy efficiency programs, to expedite Demo project implementation.

B. ORA's Preliminary Evaluation of Demo C

Demo C requires the IOUs to "develop a specification for a demonstration project where at least three DER avoided cost categories or services for which 'normative value data' presently exist (e.g., avoided resource adequacy capacity, distribution capacity deferral, voltage/reactive power management) can validate the ability of DER to achieve net benefits consistent with the Optimal Location Net Benefit Analysis."[21] The Guidance defines a "benefit" as "either economic, operational (from the utility perspective) or societal, and locational benefits [that] are generally defined as monetary value that can be assigned to some location using a set of criteria."[22]

The Guidance also requires the IOUs to demonstrate the Optimal Location Benefit Analysis methodology, herein referred to as the Locational Net Benefits Analysis (LNBA), as Demonstration Project B (Demo B). Demo C applies the LNBA methodology demonstrated in Demo B to a real-world DER deployment scenario to prove that the value predicted in the LNBA is achievable in practice. Therefore, the success of DER deployment in Demo C projects depends on the extent to which DER is able to capture the predicted location value assessed by the LNBA.

The Guidance also requires Demo C plans to (1) "include a detailed implementation schedule," (2) explain how the DER will operate in concert or displace existing infrastructure, (3) "explicitly seek to demonstrate the operations of multiple DER types in concert" and (4) "explain how minimum cost-DER portfolios were constructed

[21] Guidance, p. 6.

[22] Guidance, p. 15.

using locational factors such as load characteristics, customer mix, and building characteristics."[23]

1. *The IOUs should refine their Demo C plans to fully incorporate an LNBA analysis as a metric of success to evaluate the LNBA's ability to measure DER locational benefit.*

Demo C is inherently tied to the completion of Demo B, the Demonstration of the LNBA. Demo C should validate the ability of DER to achieve net benefits consistent with the LNBA. Currently, PG&E's Demo C demonstration area aligns with its Demo B proposed area of demonstration. However, both SCE and SDG&E's proposed areas of demonstration do not align fully and should be further refined, as discussed below.

a. PG&E Demos B and C

PG&E's chose the Chico DPA[24] for Demos B and C.[25] Since PG&E uses the same project area to evaluate its LNBA and DER procurement to measure the LNBA of the site, the LNBA value calculated through Demo B should provide a proper metric to measure the success of the LNBA to predict the value DER is able to provide through DER solicitation and deployment.

b. SCE Demos B and C

SCE's Demo B uses the Rector Subtransmission System[26] as its DPA.[27] SCE's Demo C, on the other hand, is located in the Irvine substation region[28] in Orange County.

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[23] Guidance, p. 6.

[24] The Chico DPA is located in Butte County, and is a mix of 125,000 suburban and urban customers; where 80% of the customers are Residential, 5% are Agricultural, and 15% are Commercial & Industrial. There are ten substations located in the DPA, with 37 – 12 kilovolt (kV) lines, and 4 – 4kV lines, with a peak load of 236 megawatts (MW) in 2015. PG&E states that the Chico DPA is a good candidate to meet the Demo Projects requirements because is expected to experience distribution transformer overloads in three substations over the next five years. PG&E Track 2 Demo Project Proposals, p. A-6.

[25] Demonstration Project A And B Plans of Pacific Gas And Electric Company, (U 39 E) pursuant to May 2, 2016 Assigned Commissioner's Ruling (PG&E Demo A and B Plans), June 16, 2016, p. B-3.

[26] The Rector DPA is located in the Central Valley of SCE's service territory. There are 6 substations in the Rector DPA: Goshen, Hanford, Mascot, Octol, Lourich, and Tulare, each of which is a 66/12 kV

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While SCE expressed concern that the Orange County area lacks characteristics necessary to meet the requirements of Demo B, ORA is concerned that SCE will not have an LNBA value to compare the measured results of value predicted in the LNBA. As discussed above, Demo C is a real-world test of DER's ability to capture locational value captured in the LNBA. Therefore, ORA recommends that the Commission require SCE to perform an LNBA analysis prior to soliciting DER in Demo C, either through expansion of current Demo B DPA or through a supplemental filing.

c. SDG&E Demos B and C

SDG&E's Demos B and C project areas align for one of the two DPAs. SDG&E chose its Northeast[29] and Ramona Districts[30] for implementing Demo B.[31] These DPAs

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system. There are 49,700 customers served by 9,617 service transformers and 49 feeders. The customers are a mixture of Residential and Commercial, with significant agricultural loads. SCE found that the Rector DPA was a good candidate for the Demo B location due to several factors. A near-term distribution circuit project in conjunction with a distribution substation increase project will be required in 2019 on the Goshen Substation. A reconductoring of the Rector-Lourich-Octol-Tipton-Tulare 66kV line project will be needed in the long term. Voltage support on the Mascot Substation is required due to the loss of the Goshen-Hanford-Laurel subtransmission line. Finally, new development requires a new distribution circuit on the Hanford Substation by 2020.

[27] Southern California Edison Company's (U 338-E) Implementation Plans for Demonstration Projects A and B, Appendix B, Demonstration B Implementation Plan (SCE Demo B Plan), June 16, 2016, pp. 22-23

[28] SCE identified this area as ideal for Demo C due to rapid growth driven by a planned El Toro Marine base residential development. The suburban area is predominantly expected to have residential load growth, but some commercial and industrial load growth will also occur. SCE currently has 4 circuits serving the Irvine substation: Paragon, Keeline, Elden, and Hines. SCE sees a deferment opportunity for needing to add 2 – 12.0 kV circuits on the Paragon-Keeline-Elden circuits, for filling a need of 0.8-1.2 MW. There is also a calculated deferment opportunity for adding 1-12kV circuit to the Hines circuit to meet a1 – 3.2kV need.

[29] The Northeast DPA is an urban/suburban area with 210618 customers. 183720 of those customers are residential, 120 are industrial, and 26778 are commercial. There are 150 circuits with 29 substations in the area.

[30] The Ramona DPA is a rural area with 20917 customers. 17303 of those customers are residential, 7 are Industrial, and 3607 are commercial. There are 27 circuits and 11 substations in the area.

[31] Demonstration Projects A & B Implementation Plans of San Diego Gas & Electric Company (U 902-E), Attachment 2 – Distribution Resources Plan Demonstration B Locational Net Benefits Analysis Implementation Plan, (SDG&E Demo B Plan) June 16, 2016, p. 14-15.

make up a large section of SDG&E's service territory. SDG&E will use Circuit 701[32] connected to the Mission substation and Circuit 470 Connected to the Felicita substation for Demo C.[33] Circuit 701 is located in the Northeast DPA. However, Circuit 470[34] is located in a geographically isolated, rural community outside of Escondido, which is not in either Demo B DPA. Therefore, similarly for SCE, ORA recommends that the Commission require an LNBA analysis of the Circuit 470 DPA prior to DER deployment.

2. ORA recommends the Commission explicitly order the IOUs to identify the ability of Demo C DER deployment to capture locational benefits identified in the LNBA as a metric of Demo C success.

The goal of the Demo C Projects as only DER deferral is not aligned with the guidance goal of demonstrating locational benefits as modeled in LNBA. A deferral project is a project that uses a DER to replace the "business as usual" approach of supporting capacity needs through building "wired" solutions, such as building new capacitors, new feeders and new transformers. Although deferrals may be part of the solution,[35] Project C is not specifically testing deferral projects' efficacy.

However, all of the utilities have implemented Demo C primarily as a means to test deferral project Requests for Offers (RFOs). For example, SDG&E states that

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[32] Circuit 701 is highly loaded, and has relatively high rooftop solar interconnection compared to other feeders in SDG&E territory. Circuit 701 has 4911 residential customers and 138 commercial customers. There is an estimated 3,515 kW load of solar on this circuit. Circuit 701 has a circuit capacity of 600 amps (A), and a connected kilovolt amps (kVA) of 18,330 kVA. The Circuit is connected to 1-1200 kVAr fixed capacitor, and 2-1200 kVAr switched capacitors.

[33] Responses to Track 2 Demonstration Projects Questions of San Diego Gas & Electric Company (U 902-E), Attachment 1, (SDG&E Track 2 Demo Project Proposal) June 17, 2016, p. 5-7.

[34] Circuit 470 has 1042 customers, 192 of which are commercial. There is an estimated 1816 kW of solar on this circuit. Circuit 470 has a circuit capacity of 600 A, and a 22,862 kVA. The circuit is connected to 3-1200 kVAr switched capacitors. This circuit has a forecasted capacity deficiency due to area load growth and already constrained load under current conditions.

[35] ACR DRP (Feb. 6, 2015), pp. 6-7, ("Such a DER demonstration project will either displace or operate in concert with existing infrastructure to provide the defined functions.")

"Project C will provide a platform for SDG&E to test the capability of DERs to operate during critical conditions to avoid thermal capacity deficiencies," and "… lessons learned from Demo C will help shape how future capacity deferrals and DER acquisitions are accomplished."[36] Nowhere in its response does SDG&E mention how Demo C will verify the ability of DERs to provide local benefits as calculated by the LNBA methodology as calculated by Demo B.

This is especially problematic for SDG&E and SCE, since some or all portions of their Demo C project locations are outside the Demo B DPAs, as previously discussed. Therefore, ORA recommends the IOUs evaluate the ability of DERs to capture locational benefit calculated it the LNBA and use the results of Demo C as an opportunity to further refine the LNBA methodology.

C. ORA's Preliminary Evaluation of Existing Research, Development and Demonstration Projects Related to Demos D and E

1. Demo D and E projects should be evaluated for incremental learnings from other RD&D projects.

Demonstration projects A through C address development of two analytic tools, the integration capacity analysis and LNBA, which are being developed through the DRP. These are relatively new tools and ORA supports the Commission's objectives for demonstrating these tools.[37] In contrast, there has been and continues to be numerous Smart Grid Research, Development, and Demonstration (RD&D) projects related to operating the distribution grid with high penetrations of DERs and microgrids, which are the topics of proposed Demo D and E, respectively. Based on ORA's review of the project proposals in the July 2015 DRP applications, ORA is concerned that the proposed Demo D and E projects could be duplicative of other work, and potentially waste both

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[36] SDG&E Track 2 Demo Project Proposal, pp. 2-3, 5.

[37] Comments of the Office of Ratepayer Advocates on the ALJ Ruling inviting comments on Integration Capacity Analysis (ICA) methodologies, ICA workshop report, Locational Net Benefits Analysis (LNBA) workshop and demonstration projects A and B filed in this proceeding March 3, 2016.

time and ratepayer funding. The June 17, 2016 responses to May 17 Joint Ruling questions and the June 28, 2016 workshop provided some additional details, but not enough to assuage ORA's concerns. Unlike Demo A and B projects, Demo D and E proposals generally require ratepayer funding, and there should be a clear showing that they are consistent with statutory requirements, CPUC guidance, and overall reasonableness.

As described in the following sections, ORA's review resulted in five general findings:

- Utility R&D proposals "require a demonstration that the research is not duplicative,"
- The utility filings to date do not provide sufficient detail to determine if they are duplicative or not,
- Projects do not quantify the costs for procurement of DER so total project costs are not known,
- Limited information has been provided to show that results from the demonstration projects are replicable,
- Funding for traditional "wires" solutions has been requested in PG&E's GRC that should be considered in determining demo project budgets.

The following sections provide context, summarize each project proposal, and describe additional information ORA deems necessary to ensure these programs provide unique objectives, measurable metrics to determine success and results that are likely to be replicable in full-scale deployment.

2. Substantial precedent exists for thoroughly vetting Demonstration Projects for incrementality.

While ORA acknowledges that the IOUs filed their Demo D and E projects in compliance with the DRP Guidance, ORA provides the following discussion to underscore the importance of approving demonstration projects which are incremental in nature, providing background and examples. Under California law, IOU-proposed RD&D projects are subject to defined evaluation guidelines. P. U. Code Section 740.1

(Section 740.1) sets forth five specific guidelines for the Commission to consider when reviewing an IOU RD&D proposal.[38] Within these five legislative RD&D guidelines is the requirement that "[p]rojects should not unnecessarily duplicate research currently, previously, or imminently undertaken by other electrical gas corporations or research organizations." This prohibition of duplication has become a cornerstone of the Commission's review of IOU-proposed RD&D. It has also become a substantial burden which IOUs are compelled to overcome when requesting authority to execute ratepayer-funded RD&D.

For example, in Application (A.) 10-11-002, PG&E requested authorization to invest $9.9 million in Silicon Valley Technology Corporation (SVTC), a start-up company proposing to build a new solar panel fabrication facility, the Photovoltaic Manufacturing and Development Facility (PV MDF).[39] The Commission denied PG&E's request, in part, because

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[38] Section 740.1: The Commission shall consider the following guidelines in evaluating the research, development, and demonstration programs proposed by electrical and gas corporations:

a) Projects should offer a reasonable probability of providing benefits to ratepayers.
b) Expenditures on projects which have a low probability of success should be minimized.
c) Project should be consistent with the corporation's resource plan.
d) Projects should not unnecessarily duplicate research currently, previously, or imminently undertaken by other electrical or gas corporations or research organizations.
e) Each project should also support one or more of the following objectives:
    1) Environmental improvement.
    2) Public and employee safety.
    3) Conservation by efficient resource use or by reducing or shifting system load.
    4) Development of new resources and processes, particularly renewable resources and processes which further supply technologies.
    5) Improve operating efficiency and reliability or otherwise reduce operating costs.

[39] A.10-11-002, Amendment to Application of Pacific Gas and Electric Company for Share of Costs of California Solar Photovoltaic Manufacturing Development Facility Under U.S. Department of Energy Photovoltaic Manufacturing, p. 1 (re-filed July 15, 2011).

> the focus of the PV MDF is on commercialization of solar panel manufacturing technology. Every solar panel manufacturer may be assumed to be focused on commercialization. While the existence of PV MDF might marginally accelerate that process, it almost certainly duplicates the efforts of existing and future manufacturers . . . For these reasons, we conclude that investment of ratepayer funds in this project is not authorized by Pub. Util. Code §§ 740 and 740.1.[40]

Similarly, in A.11-11-017, PG&E requested $109 million over four years to support its Smart Grid Pilot Deployment (SGPD) Projects.[41] The Commission granted, in part, and denied, in part, the SGPD Projects. The Commission approved, in part, three of the SGPD Projects (Line Sensor, Volt/Var, and Detect and Locate) because they were not duplicative,[42] but denied the Smart Grid Customer Outreach Project because the "Commission finds nothing in the proposed Outreach project that is unique or non-duplicative of approaches in other outreach efforts conducted by the utilities."[43]

In A.11-07-008, the IOUs filed a joint application to establish a five-year cooperative RD&D agreement with the Lawrence Livermore National Laboratory (LLNL) known as the "California Energy Systems for the 21st Century Project" (CES-21 Project).[44] Unlike the SVTC and SGPD Projects that requested approval of specific projects, the CES-21 Project was a five-year RD&D program that allowed the IOUs to select individual projects after the Commission authorized funds. In D.12-12-031, the Commission approved the CES-21 Project recognizing it is governed by the guidelines

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[40] D.12-05-014, p. 9. Also, D.12-05-014, Conclusion of Law (CoL) 1, p. 12: "Investment of ratepayer funds in SVTC is not authorized by Pub. Util. Code §§ 740 and 740.1."

[41] A.11-11-017, Smart Grid Pilot Deployment Project Application of Pacific Gas and Electric Company, p. 1 (filed November 21, 2011).

[42] D.13-03-032, Findings of Fact (FoF) 17, 37, 49, pp. 73, 75-76.

[43] D.13-03-032, FoF 85, p. 80.

[44] A.11-07-008, Application of Pacific Gas and Electric Company (U 39 M), San Diego Gas & Electric Company (U 902 E), and Southern California Edison Company (U 338 E) for Authority to Increase Electric Rates and Charges to Recover Costs of Research and Development Agreement with Lawrence Livermore National Laboratory for 21st Century Energy Systems, p. 1 (filed July 18, 2011)

set forth in Section 740.1.[45] It also made clear projects "require a demonstration that the research is not duplicative."[46] To guarantee a prohibition against duplication was a priority of the CES-21 Project, in 2013 Legislature codified P. U. Code Section 740.5 (Section 740.5) into law, in part, to ensure "that there not be a duplication of research being done by other private and governmental entities."[47]

Finally, in establishing the Electric Program Investment Charge (EPIC) Program, a statewide RD&D program focused on providing "public interest investments in applied research and development, technology demonstration and deployment, and market support, and market facilitation, of clean energy technologies and approaches for the benefit of electricity ratepayers,"[48] the Commission stated a guiding principle of the EPIC

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[45] D.12-12-031, CoL 5, p. 90, (Section 740.1 sets forth guidelines for the Commission to consider in evaluating research development and demonstration programs proposed by electrical and gas corporations.)

[46] D.12-12-031, CoL 9, p. 91.

[47] Section 740.5(d). Codified into law by Senate Bill 96 [Chapter 356, Statutes of 2013]. SB 96 (33) states:

> This bill would prohibit the Public Utilities Commission, in implementing the 21st Century Energy System Decision, as defined, from authorizing recovery from ratepayers of any expense for research and development projects that are not for purposes of cyber security and grid integration and would limit total funding for research and development projects for the purposes of cyber security and grid integration from exceeding $35,000,000. The bill would require that all cyber security and grid integration research and development projects be concluded by the 5th anniversary of their start date. The bill would prohibit the Public Utilities Commission from approving recovery from ratepayers of certain program management expenditures proposed in the 21st Century Energy System Decision proceeding. The bill would require the Public Utilities Commission to require the Lawrence Livermore National Laboratory, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company to ensure that research parameters reflect a new contribution to cyber security and grid integration and that there not be a duplication of research being done by other private and governmental entities. The bill would require the participating electrical corporations to jointly report specified information to the Public Utilities Commission by December 1, 2013, and 60 days following conclusion of all research and development projects, and would require the Public Utilities Commission, upon determining that each report is sufficient, to report that information to the Legislature.

[48] D.12-05-0347, p. 1; in R.11-10-003.

Program is the "[e]fficient use of ratepayer monies."[49] The Commission defined "[e]fficient use of ratepayer funds as "funding should not be used to support activities or efforts that are duplicative of efforts that are being undertaken elsewhere or that are more expensive than necessary to achieve the goals."[50] To make the point abundantly clear, however, the Commission also ordered the IOUs to demonstrate "[h]ow the investment plan[s] address[] the principles articulated in P. U. Code Sections 740.1 and 8360."[51] PG&E's 2012 EPIC application provides an example of how requested projects were compared to other programs.[52]

The May 17, 2016 Joint Ruling recognized the statutory need to avoid duplication in asking for descriptions of other relevant demonstration projects/pilots and funding sources.[53] It also sought additional information on the proposed projects which would have allowed comparison to other related projects.[54] As discussed in Sections D and E below, the utility responses filed June 17, 2016 provided insufficient information to allow such a comparison.

3. *At Least Seven Related Smart Grid Programs have goals similar to Demos D and E.*

Safe and reliable operation of distribution grids and microgrids with high penetration of DERs are characteristics of a Smart Grid. RD&D programs to develop the Smart Grid have received attention from policy makers as a tool to meet clean energy goals, and by utilities both to maintain good service as generation sources move into the distribution grid and as a source of capital investment and profits. The result has been substantial public and private investment since the term "Smart Grid" came into common

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[49] D.12-05-037, Ordering Paragraph 2(f), p. 99.

[50] D.12-05-037, p. 14.

[51] D.12-05-037, OP 12(e), p. 104.

[52] Appendix B to PG&E Electric Program Investment Plan, filed November 1, 2012 in A-12-11-003.

[53] May 17 Joint Ruling, Appendix A, pp. 1-2, questions 7 and 12.

[54] *Id.* questions 1, 2, 6, 8, 9, 10, 11, 13, 14.

use. The following is a non-comprehensive list of programs and/or funding sources for Smart Grid RD&D projects:

- Department of Energy (DOE) American Recovery and Reinvestment Act (ARRA) Smart Grid Investment Grant,[55]
- DOE Sunshot Initiative,[56]
- CES-21,[57]
- CPUC Smart Grid Pilot Deployment,[58]
- California PIER program,[59]
- California Solar Initiative (CSI) RD&D,[60]
- EPIC,[61]

Other potential sources of projects relevant to Demonstration D and E projects include programs in other states like Hawaii; industry studies, for example by Solar City;

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[55] This includes Electric Distribution Systems Project topic area. Applications in this topic area will be aimed at adding smart grid functions to local electric distribution systems in retail electricity markets. Projects will primarily involve adding smart grid functions to devices, equipment, and/or software applications including substations, transformer banks, feeder lines, pole top transformers, and customer interconnection and communications systems. Projects in this area can involve distribution automation systems; Supervisory Control and Data Acquisition (SCADA) systems; distribution monitoring, control, and optimization systems; load control systems for lowering peak demand; and electric distribution applications of distributed generation and energy storage equipment. See http://energy.gov/oe/downloads/smart-grid-investment-grant-topic-areas.

[56] The SunShot Initiative issues competitive solicitations that fund selective research projects aimed at transforming the ways the United States generates, stores, and utilizes solar energy. The targeted strategies supported by the SunShot Initiative include activities that seek to…[f]oster collaboration for utility-scale solutions and clear the way for high penetration solar energy. See http://energy.gov/eere/sunshot/systems-integration.

[57] *See* Section II.C.2 above.

[58] *See* Section II.C.2. above and further discussed below.

[59] The PIER Electric program encumbered the final PIER electricity funds in June 2013. The Energy Commission continued to manage the remaining active projects through the end of 2015. The Energy Commission will release a final report, which will showcase the benefits of the entire PIER Electric Program since the inception in 1997. Project PIR-12-004 had a budget of approximately $3 million for this "Integrated Solar PV, Advanced Compressed Air Energy Storage, and Microgrid Demonstration Project." *See* the PIER 2015 Annual Report, CEC-500-2016-CMF, April 2016, pp. 1, 16.

[60] *See* http://www.calsolarresearch.org/ and discussion below.

[61] *See* Section II.C.2. above, http://www.energy.ca.gov/research/epic/index.html, and discussion below.

and utility supported studies, for example by EPRI or the Edison Electric Institute. ORA's preliminary investigation of Demo D & E focused on the overlap between the DRP demonstration projects and two of these programs: EPIC and the California Solar Initiative (CSI) RD&D programs.

The Commission established the EPIC Program to "provide public interest investments in applied research and development, technology demonstration and deployment, and market support, and market facilitation, of clean energy technologies and approaches for the benefit of electricity ratepayers."[62] The Commission authorized the CEC and IOUs (collectively, EPIC Administrators) to invest approximately $1.5 billion from 2012-2020 in RD&D for the benefit of the state and ratepayers. The CEC administers 80% of the funds and the IOUs administer 20% of funds.[63] Every three years, the EPIC Administrators submit triennial investment plans to the Commission for review and approval. The triennial investment plans contain the EPIC Administrators' proposed R&D project portfolios. To date, the Commission approved approximately $1.0 billion in ratepayer funds.[64]

In February 2016, the EPIC Administrators submitted their most recent EPIC annual reports. The CEC's EPIC annual report shows the CEC approved at least 18 projects related to the DRP at approximately $44 million.[65] Including the approximate $20 million in matching funds from EPIC-award recipients, the total combined funds

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[62] D.12-05-0347 (R.11-10-003), p. 1.

[63] D.12-05-037, p. 100, (OP 5).

[64] D.13-11-025 established a 2012-2014 budget of approximately $508 million, per finding of facts 6 through 9. D.15-04-020 established a 2015-2017 budget of approximately $510 million, per the table on page 4. ORA did not review project objectives where the CEC did not self-report the DRP relationship. Other projects may be related, as ORA found for the IOU projects.

[65] CEC report CEC-500-2016-014-CMF dated April 2016. Appendix B includes descriptions of each active and approved project which identify "CPUC Proceedings addressing issues related to this EPIC project." *See* Attachment 2 for specific projects. Attachment 1 shows the cost calculation, as compiled by ORA.

designated by the CEC for DRP-related activities are approximately $65 million.[66] This total amount only accounts for the CEC's 2012-2014 triennial investment plan budget and does not reflect any additional investment made as part of its 2015-2017 triennial investment plan.

The IOU EPIC Administrators invested in DRP-related projects, but are restricted to the area of technology demonstration and deployment. For example, PG&E's EPIC annual report shows it has approximately 13 DRP-related EPIC projects and has spent approximately $9 million.[67] SCE's EPIC annual report shows it has approximately 11 DRP-related EPIC projects and has also spent approximately $9.7 million.[68] SDG&E's EPIC annual report shows it has approximately nine DRP-related EPIC projects and has spent less than $0.5 million.[69] Details on the DRP related EPIC programs are provided in Attachments 1-5.

The CSI Program also funds related RD&D work. The CSI Program was codified into law, as P. U. Code Section 2851 (Section 2851), when the Governor signed Senate Bill 1 in 2006. Within the CSI Program, the Legislature earmarked $50 million for RD&D to explore "solar technologies and other distributed generation technologies that employ or could employ solar energy for generation or storage for electricity or to offset

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[66] *Id*.

[67] PG&E Annual Report on the EPIC program, filed February 29, 2016 in A.14-04-034, includes descriptions of each active and approved project. Each project has an objective, eight of which include "This project contributes to objectives in the following CPUC proceeding(s): DRP R.14-08-013." ORA considered five additional projects as DRP related based on the stated objectives: projects 1.02, 1.14, 2.01, 2.19, 2.29. *See* Attachment 5 for specific projects. Attachment 1 shows the cost calculation, as compiled by ORA.

[68] SCE Annual Report on the EPIC program, filed February 29, 2016 in A.14-04-034. SCE's project descriptions generally do not refer to related CPUC proceedings and only one project, the Integrated Grid Project (IGP), references DRP. The remaining programs were deemed related to DRP based on ORA's review of the project objectives, metrics, and status. *See* Attachment 3 for specific projects. Attachment 1 shows the cost calculation, as compiled by ORA.

[69] SDG&E Annual Report on the EPIC program, filed February 29, 2016 in A.12-11-001. SDG&E's project descriptions do not refer to related CPUC proceedings. The programs were deemed related to DRP based on ORA's review of the project objectives, metrics, and status. *See* Attachment 4 for specific projects. Attachment 1 shows the cost calculation, as compiled by ORA.

natural gas usage."[70] As with the RD&D programs and projects noted above, the Legislature directed the Commission to "ensure there is no duplication of efforts." Therefore, in 2007 the Commission issued D.07-09-042 establishing a research, development, demonstration and deployment plan for the CSI Program.[71] The Commission identified principles and objectives of the CSI RD&D Program and required it to adhere to seven key goals, including:

1. Fill knowledge gaps to enable successful, wide-scale deployment of solar distributed generation technologies,
2. Overcome significant barriers to technology adoption,
3. Support efforts to address the integration of distributed solar power into the grid in order to maximize its value to California ratepayers.[72]

To support the CSI Program, and consistent with the principles articulated, the Commission has approved four funding rounds for RD&D projects.[73] The projects approved by the Commission address similar objectives as identified in the DRP and for which the IOUs partnered with grant recipients to execute. Comparisons between DRP project proposals and related EPIC and CSI RD&D programs are provided in Sections D and E below.

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[70] Section 2851(c)(1): In implementing the California Solar Initiative, the commission shall not allocate more than fifty million ($5,000,000) to research, development, and demonstration that explores solar technologies and other distributed generation technologies that employ or could employ solar energy for generation or storage of electricity or to offset natural gas usage. Any program that allocates additional moneys to research, development, and demonstration shall be developed in collaboration with the Energy Commission to ensure there is no duplication of efforts, and adopted by the commission through a rulemaking or other appropriate public proceeding. Any grant awarded by the commission for research, development, and demonstration shall be approved by the full commission at a public meeting. This subdivision does not prohibit the commission from continuing to allocate moneys to research, development, and demonstration pursuant to the self-generation incentive program for distributed generation resources originally established pursuant to Chapter 329 of the Statutes of 2000, as modified pursuant to Section 379.6."

[71] D.07-09-042, Opinion Establishing A Research, Development, Demonstration and Deployment Plan for the California Solar Initiative (September 20, 2007).

[72] D.07-09-042, Attach. A, p. A3.

[73] *See* Resolutions E-4317, E-4354, E-4470 and E-4629.

D. ORA's Preliminary Evaluation of Demo D

Demo D requires the IOUs to "demonstrate distribution operations at high penetration of DERs," directing them to:[74]

- Develop a specification for a demonstration of high DER penetrations that integrates the Utilities' distribution system operations, planning and investment for implementation,
- Provide analysis of potential benefits and locational values associated with high-DER penetration,
- Conduct projects at the Substation level and involve up to 5 circuits,
- Explicitly demonstrate the operations of multiple DERs in concert, and operational coordination with third-party DER owners/operators/aggregators,
- Explain how DER portfolios were constructed,
- Employ some quantity of third party-owned and -operated DERs, and may include Utility-owned DERs,
- Commence the demonstration no later than 1 year after Commission approval of the DRP.

While the Commission's goals for ordering Demo D are laudable, it is important to note that questions regarding the impact of high penetrations of DER, particularly intermittent resources like rooftop PV, on distribution system operations have been the subject of much RD&D work, as discussed extensively in Section C. Some of these previously authorized projects appear to have overlapping objectives with the proposed Demo D projects as discussed for each utility in the sections that follow.

ORA's review of EPIC projects found numerous projects that relate directly to Demo D, as shown by the following excerpts from the EPIC 2016 Annual Reports:

- SCE's The Beyond the Meter (BTM) project – "Demonstrate the use of a DER management system to interface with and control DER based on customer and distribution grid use cases. It will also demonstrate the ability to communicate near-real time information on the customer's load

[74] ACR DRP (Feb. 6, 2015), Attach. p. 7.

management decisions and DER availability to SCE for grid management purposes."[75]

- SCE's Distribution Optimized Storage project – "Demonstrate end-to-end integration of multiple energy storage devices on a distribution circuit/feeder to provide a turnkey solution that can cost-effectively be considered for SCE's distribution system, where identified feeders can benefit from grid optimization and variable energy resources (VER) integration."[76]
- SCE's Outage Management and Customer Voltage Analytics Demonstration project – "A pilot project will be conducted to understand how voltage and consumption data can be best collected, stored, and integrated with T&D applications to pro-vide analytics and visualization capabilities."[77]
- SCE's Integration of Big Data for Advanced Automated Customer Load Management program – "Demonstrate the use of big data acquired from utility systems such as SCE's advanced metering infrastructure (AMI), distribution management system (DMS), and Advanced Load Control System (ALCS) to determine the optimal load management scheme and execute by communicating to centralized energy hubs at the customer level."[78]
- SCE's Dynamic Power Control Program – "Demonstrate the use of the latest advances in power electronics and energy storage devices and controls to provide dynamic phase balancing as well as providing voltage control, harmonics cancellation, sag mitigation, and power factor control."[79]
- SCE's Optimized Control of Multiple Storage Systems project – "Demonstrate the ability of multiple energy storage controllers to integrate with SCE's Distribution Management System (DMS) and other decision making engines to realize optimum dispatch of real and reactive power based on grid needs.[80]

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[75] *See* Attachment 3 for details.

[76] *See* Attachment 3 for details.

[77] *See* Attachment 3 for details.

[78] *See* Attachment 3 for details.

[79] *See* Attachment 3 for details.

[80] *See* Attachment 3 for details.

- PG&E's Energy Storage for Distribution Operations project - Demonstrate the ability of a utility operated energy storage asset to address capacity overloads on the distribution system and improve reliability."[81]
- PG&E's Pilot Distributed Energy Management Systems (DERMS) project – "Demonstrate new technology to monitor and control DERs to manage system constraints and evaluate the potential value of DER flexibility to the grid. The DERMS pilot will drive learning about the people, process, and technology needed to operate the high DER penetration grid of 2025."[82]
- PG&E's Test Smart Inverter Enhanced Capabilities – "Photovoltaics project - This EPIC project will deploy smart inverters on one or more feeders to evaluate their effectiveness in improving PV integration and mitigation safety risks."[83]
- PG&E's DG Monitoring & Voltage Tracking project – "This project aims to utilize the voltage measurement capabilities of SmartMeters to monitor DG output and identify voltage fluctuations caused by the intermittent nature of distributed renewable resources."[84]
- SDG&E's Smart Distribution Circuit Demonstrations project – "The objective of this project is to perform pilot demonstrations of smart distribution circuit features and associated simulation work to identify best practices for integrating new and existing distribution equipment in these circuits."[85]
- SDG&E's Distributed Control for Smart Grids project – "This phase [of the project] will include the field demonstration of the proposed Advanced Distribution Control System which should gather and process the data and measurements from smart devices in an individual feeder or a larger distribution circuit region, coordinate and manage the operation of the controllable devices."[86]
- SDG&E's Data Analytics in Support of Advanced Planning and System Operations project – "This demonstration project will determine the

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[81] *See* Attachment 5 for details.

[82] *See* Attachment 5 for details.

[83] *See* Attachment 5 for details.

[84] *See* Attachment 5 for details.

[85] *See* Attachment 4 for details.

[86] *See* Attachment 4 for details.

quantity and location of data-generating devices in the power system, the generation capabilities of these de-vices, and how the resulting data is being stored and archived."[87]

- SDG&E's Integration of Customer Systems into Electric Utility Infrastructure project - "[This project] will demonstrate the safe and reliable interoperability of customer systems with the distribution and transmission system and CAISO operations to improve grid operations and thereby increase ratepayer satisfaction and benefits."[88]
- SDG&E's Collaborative Programs in RD&D Consortia project - "By working through international R&D consortia, a much larger pool of knowledge coming from worldwide demonstrations related to the various project areas of the EPIC program will be captured than world be achievable in the few smaller demonstrations that are funded by SDG&E's EPIC budget alone."[89]

Each of these projects addresses an objective that is relevant to CPUC guidance for Demo D. In general, these projects have a narrower scope than Demo D, but they all provide learnings that are relevant to it. It is possible that Demo D is unique in that it proposes to demonstrate the combined learnings of all of these foundational EPIC projects, and others ORA has not reviewed. However if that is the case, significant time will be required to complete the EPIC projects, document the results, and incorporate these results into the Demo D plans. The proposed schedules for Demo D projects will not provide this opportunity based on the status EPIC projects.[90] In Section 5 below, ORA recommends that it may be appropriate for Demo D to be a "meta-project" that analyses the results of EPIC and other projects and combines them into a single set of findings, rather than Demo D consisting of additional field demonstration projects.

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[87] *See* Attachment 4 for details.

[88] *See* Attachment 4 for details.

[89] *See* Attachment 4 for details. This project should allow SDG&E to gather learnings from Germany, which has a high penetration of DER.

[90] For PG&E, only one of the 33 active projects was completed as of December 31, 2015. *See* PG&E 2016 Annual EPIC Report, p. 4.

One potentially unique element of the requirements for Demo D projects is the "analysis of potential benefits and locational values." At face value, this seems to substantially overlap with the Demo C projects focused on the LNBA. However, as discussed below, none of the IOUs' proposals included a discussion of how this requirement would be met, and thus it appears to be excluded from the projects. If the CPUC intended these projects to evaluate benefits and locational value, it should reiterate this requirement and clarify what information it seeks beyond the objectives of Demo C projects.

1. PG&E's proposed Demo D should (1) further clarify incrementally with existing research (2) characterize proposed DER for procurement (3) address concerns related to project scalability and (4) coordinate funding requests with the current GRC authorization

PG&E proposes to perform this project at the Huron substation in rural Fresno County, which was identified as one of PG&E's top five highly [DER] penetrated substations using its streamlined ICA methodology.[91] PG&E requested funding to upgrade this substation in its current GRC.[92] For this project, PG&E proposes to add new DER to this region via a competitive solicitation, and operate or control this new DER to minimize the negative impacts of the existing DER and loads. PG&E estimates the project to cost $2.1 million plus the cost for any DER to be procured.[93]

PG&E's original DRP, its June 17 filing, and its June 28 workshop presentation provided the best description of the Demo D proposal, with good definitions of the project area and the need for this project, objectives and learning opportunities, and schedule and cost. However, ORA also has four concerns with the proposed project.

First, PG&E has not adequately defined the overlap between this project and those in EPIC and CSI RD&D programs. PG&E's DRP application references EPIC

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[91] PG&E DRP Application (Jul. 1, 2015), p. 57.

[92] PG&E Demos C, D E Detailed Project Filing (Jun. 17, 2016), p. A-17.

[93] *Id*. p. A-16.

project 2.2, but this reference is not provided in its June 17, 2016 response to questions 7[94] and 12.[95] EPIC project 2.2 is titled "Pilot Distributed Energy Resource Management Systems (DERMS)" and its stated objectives include:[96]

- Demonstrate new technology to monitor and control DERs to manage system constraints and evaluate the potential value of DER flexibility to the grid.
- This project contributes to objectives in the following CPUC proceeding(s): DRP R.14-08-013 / A.15-07-006.

This EPIC project has $477,287 of funds encumbered and was in the "Plan/Analyze" phase as of the 2015 annual report.[97] It appears that DERMS is an integral element of PG&E's proposed Demo D and this relationship should be fully defined in PG&E's Demo D proposal so any overlap is revealed.

PG&E also partnered with SunPower Corporation for a CSI RD&D proposal titled "PV and Advanced Energy Storage for Demand Reduction." The Commission awarded $1,875,000 to demonstrate that the integration of PV and energy storage will be higher value than either technology alone. The project includes tasks to increase demand reduction and verify benefits of solar coupled with storage, and also assess the reliability and performance of three different storage technologies."[98] As with EPIC 2.2, there appears to be overlap which must be defined.

Second, it is not clear why PG&E cannot characterize the DER technologies to be used in this project in response to question 8.[99] PG&E has characterized overload

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[94] May 17 Joint Ruling, Ap. A, p. 1, (Question 7. Describe any relevant characteristics of the location chosen for the project (e.g., rural or urban area, current load, number of customers, current DER penetration, and projections of load and DER penetration.).

[95] May 17 Joint Ruling, Ap. A, p. 2, (Question 12. What other funding and/or pilots will be leveraged by deploying the project in the proposed area?).

[96] PG&E EPIC 2015 Annual Report (Feb. 29, 2016), p. 55.

[97] *Id*.

[98] Resolution E-4354, p. 27.

[99] May 17 Joint Ruling, App. A, p. 2, (Question 8. If known, explain what specific DER technologies will

(continued on next page)

conditions due to customer loads in the summer, and due to utility scale PV in the winter, so it is unclear why it cannot provide a better definition of the specific DER technologies it would include in this project.[100] As discussed in more detail below, PG&E has performed enough analysis on this substation to request funding for Huron substation upgrades in the current GRC. This analysis should be used to provide a basic hypothesis of the types of DER that could resolve the overload conditions, which would help estimate the DER procurement costs that are currently unquantified.

Third, it is not clear if the integration issues for this project, which appear to be largely due to the presence of two 10 MW PV systems connected to a substation bank with an 18.8 MW capacity, are typical of PG&E's DER integration issues generally. While this may be a real situation that requires a real solution, it is not clear how this situation occurred, or how typical it is within PG&E's service territory. For example, a more common scenario could be caused by the growth of smaller PV systems, some of which will be equipped with smart inverters that could provide services to mitigate voltage issues. This highlights the importance of Question 4[101] in the May 17, 2016 ACR regarding replicability, which was not adequately addressed in PG&E's June 17, 2016 filing.

Finally, there are inconsistencies between the description of "wires" alternatives requested in the GRC and the description in the DRP filings. PG&E notes that it has requested funding for upgrades to the Huron substation in the current GRC: "Specifically, PG&E has requested funding to install this second Huron transformer to accommodate projected levels of DER penetration. In addition, the existing transformer is also projected to overload due to peak demand conditions that occur outside of peak

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be selected and why.)

[100] PG&E's needs are best described in slides 98 and 9 of its June 28, 2016 workshop presentation.

[101] May 17 Joint Ruling, App. A, p. 1, (Question 4. What is the project's potential for replication across

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distributed generation hours."[102] PG&E's filings to date define no DER currently within the Huron circuits, or those forecasted, beyond the 20 MW of utility scale PV. ORA would like to understand the "projected levels of DER" that need to be accommodated. PG&E's GRC application reveals that a temporary transformer was installed at Huron to handle load from an adjacent circuit.[103] In addition, ORA discovery in the GRC revealed that PG&E's forecast for the proposed new Distributed Energy Resources Integration Capacity (DERIC) program includes the following upgrades for Huron:[104]

1. Replace bank due to saturation, Bank 1,[105]
2. Replace Fixed Capacitor banks with Switched, enable Supervisory Control and Data Acquisition (SCADA), Bank 2,
3. Install SCADA on existing Switched Capacitor banks, Bank 2,
4. Upgrade voltage regulator banks to closed-delta, enable SCADA, Bank 2,[106]

It therefore appears that PG&E currently has at least two transformer banks at Huron. PG&E forecasted replacement of the transformers on one bank and forecasted replacement of line voltage control devices on the other bank. This is not consistent with the line diagram provided in PG&E's workshop presentation.[107]

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the system?)

[102] June 17, 2016 filing, p. A-17.

[103] PG&E installed a temporary bank at Huron in May 2014 to "support the added pumping load until Schindler Bank 2 is installed in 2015." *See* PG&E's 2017 GRC, A.15-09-001, Exhibit PG&E-4 Workpapers, p. WP 13-18, line 181 and pp. WP 13-20 and WP 13-21, line 16.

[104] Attachment 1 to PG&E's response to DR-ORA-22-Q5, in PG&E's 2017 GRC, A.15.09.001.

[105] Transformer saturation is an indication of overload conditions.

[106] An open-delta transformer bank uses fewer transformers, but has limited performance. The closed-delta configuration uses three transformers for better performance.

[107] PG&E presentation from the June 28, 2016 Demonstration Projects C, D, and E Workshop, Slides 6 and 7. *See* http://www.cpuc.ca.gov/General.aspx?id=5071.

2. *SCE's proposed Demo C appears cost-effective but requires further clarification of (1) locational benefits evaluation metrics and (2) evaluation of project goals in light of the CSI RD&D partnership with NREL (3) budget risks associated with potentially unknown and uncapped DER procurement costs and (4) a protracted timeline in light of existing project funding.*

SCE proposes to perform this project at the Camden and Johanna Jr. substations in urban Orange County. These substations were not listed as circuits with high levels of distributed generation (DG) penetration in the DRP application, but the June 17 filing indicates that the Camden substation will have a DER penetration greater than 17% in 2017.[108]

For this project, SCE will test, deploy, and operate systems in the field that monitor and control multiple DERs, including third-party owned DERs, to ensure that high levels of DER do not reduce the safety and reliability of the distribution system. SCE estimates the cost of this project to be $23.65 million, all of which will be funded through existing EPIC Integrated Grid Project (IGP).

The key strength of SCE's proposal is that it fully leverages the existing IGP project and as such SCE is not requesting any additional funding in this DRP proceeding, except potential DER procurement costs. In addition, SCE acknowledges the CPUC's direction to analyze the potential benefits and location values of high penetrations of DER. However, ORA found the following weaknesses with the project.

First, while SCE acknowledges the CPUC direction to analyze the potential benefits and location values in response to question 1,[109] the proposal provides no explanation of how this objective will be achieved.

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[108] Current DER levels from DRP Appendix F, page 32 of the appendices. Projected DER penetration are from SCE's June 17 filing, pages 24 and 25. PRP projects with locations yet to be defined are not included in the 17% figure.

[109] Question 1 for Demo D addresses objectives and methods. May 17 Joint Ruling, App. A, p. 1.

Second, SCE fails to address potential overlap with a related CSI RD&D project. The National Renewable Energy Laboratory (NREL) was awarded $1.6 M for "Analysis of High-Penetration Levels of PV into the Distribution Grid in CA." SCE partnered with NREL and the Commission approved the project because "[h]igh penetration of PV onto California's transmission and distribution system could pose a major slowdown in deployment of PV. This project proposes solutions to both the hardware and software hurdles facing high penetration PV."[110] While this project could be fully funded by other programs, the estimated budget does not include the cost of procuring additional DER resources (if necessary.)[111] This poses a similar budgetary risk as in PG&E's proposal.

Third, the Track 2 schedule is dependent on the adoption of SCE's Demo D project even though this project would fully leverage projects already approved. The result is a final report in 1st quarter 2020. Ideally, SCE should be able to accelerate the start of Demo D by leveraging the existing IGP.

Finally, while SCE states that it will analyze the impacted region before and after DER deployment, it is not clear how this will be achieved when there are already high levels of penetration on some of the circuits.[112] In addition, neither the proposed schedule nor the table of deliverables explicitly provide for pre-deployment measurements, analysis or reporting. ORA's experience with demand-side customer programs indicates that baseline/pre-deployment measurements are essential to determining the impacts of distribution upgrades and should be provided.

3. SDG&E's Demo D project (1) lacks sufficient cost information, (2) identifies but does not clearly leverage related projects, (3) should be modified to accommodate changing smart inverter standards and (4) would benefit

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[110] Resolution E-4317, p. 30.

[111] SCE June 17, 2016 response to May 17 Joint Ruling, p. 29.

[112] One circuit is projected to have 50%+ penetration in 2017 and three more with 10-15. *See* SCE's presentation from the June 28, 2016 Demonstration Projects C, D, and E Workshop, Slide 6, available at http://www.cpuc.ca.gov/General.aspx?id=5071.

from pre-construction baseline measurements capturing inland seasonality.

SDG&E proposes to perform this project on its Valley Center substation located in rural San Diego County near Escondido. The penetration of DER on this substation was not provided.[113] SDG&E estimates the project costs to be $9 million excluding procurement of DER. The bulk of the budget, $8.5 million, is for field installations, but neither the original application nor the responses to the May 17, 2016 Assigned Commissioner's Ruling (ACR) describe what type of equipment would be installed.[114]

Strengths of SDG&E's proposal are that two related EPIC projects are incorporated into the project scope. SDG&E also reserves three months in the schedule to "establish baseline operations" which ORA interprets as measuring and documenting circuit conditions before attempting to install DER and control equipment. SDG&E's objectives, provided in response to question 1,[115] also provide a limited set of objectives that can be tested, rather than overly broad objectives that cannot be tested.[116] As with proposals from other utilities, these strengths are accompanied by weaknesses.

The first limitation of SDG&E's proposal is that it does not reveal the scope of work to be performed beyond the most basic nature of the work. The clearest discussion of tasks is in the schedule provided in response to question 13,[117] but this simply indicates

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[113] Table 3 of SDG&E's July 1, 2015 DRP application, p. 31 lists circuits with DER capacity greater than 25% of the circuit capacity, but substation names were not given. SDG&E's June 17 filing and June 28 workshop presentation indicate that 12 MW of DER is connected to this substation, but the capacity of the substation is not given.

[114] Unlike the other Demo D plans, SDG&E does not mention monitoring and control systems for these DERs. No detail is provided regarding what is included in the $8.5 million estimate for "field installations." SDG&E provided some additional details verbally during the June 28 workshop, but these need to be documented.

[115] May 17 Joint Ruling, p. 1 (Question 1. Should any of the demonstration projects, either as a category across all utilities or for a specific utility, be prioritized for Commission approval, or should all projects be approved at the same time? Explain the reasons. Are there specific timing considerations that should be factored?).

[116] SDG&E's response to question 1 provides two worthy objectives: use storage devices to better match PV production with peak demand; use smart inverters to provide voltage support.

[117] May 17 Joint Ruling, Ap. A p. 2, (Question 13. Provide a schedule for project design and deployment.

(continued on next page)

that SDG&E anticipates performing both simulations, which could be either computer or laboratory simulations, and field installations and measurements. Responses to questions 9[118] and 11[119] mention that solicitations for DER portfolios maybe be performed, but only three months is provided in the schedule to "procure equipment/conduct solicitations."

Second, while SDG&E mentions two related EPIC projects, it does not appear that SDG&E is leveraging them to reduce the budget request or schedule duration for this proposed project. Integrating and leveraging existing RD&D projects into these projects is one of ORA's primary concerns, as discussed in Section C.

Third, SDG&E's June 28, 2016 presentation added a new element to this project: "DERs must be able to regulate voltage on the distribution system without interfering with utility Volt/VAr control." ORA has concerns with this statement which implies DER providers have the burden to unilaterally adapt the use of smart inverters to match each IOU CVR scheme and system. The CPUC adopted Phase 1 smart inverter features that are anticipated to have a positive impact on feeder voltage profiles. Inverter manufacturers will be required to comply with these functions and adopt others in the future. This is the new baseline condition and existing utility systems including Volt/VAr control should modify their systems to accommodate smart inverter operation, not the inverse.

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Identify major milestones for the project and the description of the activity to be performed. Include a timetable (by year and quarter) showing when each step will be completed, including when deliverables are due.).

[118] May 17 Joint Ruling, Ap. A p. 2, (Question 9. Describe what role third-party DER technology vendors have in the project.).

[119] May 17 Joint Ruling, Ap. A p. 2, (Question 11. Provide a breakdown of the project by activity (e.g., engineering, installation of field devices, modeling, data gathering, data analysis) and an estimated cost for each activity. Include the grand total for this project.).

Finally, the schedule indicates baseline conditions will be determined in the winter of 2016/2017. Given the inland location in southern California, it is reasonable to assume significant shifts in circuit loading between hot summers and cool winters.[120] If baseline conditions for all seasons are to be determined analytically rather than measured, this should be clarified.

4. ORA General Findings Regarding Demo D Projects

ORA's review of the utility Demo D filings and other related RD&D projects resulted in the following general findings:

- Integration of high-penetrations of DER is the subject of numerous RD&D projects nationwide and in California,
- EPIC projects related to Demo D are in process, but results from these projects will generally not be available to guide Demo D scope, design, and implementation per the current IOU schedules,
- These Demo D project proposals do not include a demonstration that the research is not duplicative,
- For projects proposed to include procurement of DER, this cost is unquantified and so total project costs are not known,
- Limited information has been provided to show that results from the demonstration projects are replicable,
- These Demo D proposals do not demonstrate compliance with CPUC guidance to "provide analysis of potential benefits and locational values associated with high-DER penetration,"
- The schedule for baseline measurements prior to DER integration is not clearly articulated,
- Funding for wired alternatives has been requested in PG&E's GRC which should be factored into Demo D funding authorization.

In sum, ORA finds that the IOUs filings to date regarding Demo D lack required information and do not support a determination that ratepayer funding should be provided.

[120] For Escondido, the average August high temperature is 89Farenheit (F) and the average December low temperature is 42F, per U.S. Climate Data.

5. *ORA Recommendations Regarding Demo D Projects*

Based on the findings above, ORA has three recommendations regarding the utility Demo D project proposals:

- The CPUC and utilities should focus on Demo A, B and C projects and schedule evaluation of Demo D projects in a later phase of the DRP,
- The CPUC should clarify its direction to "provide analysis of potential benefits and locational values associated with high-DER penetration," and how this requirement differs from the requirements of Demo C projects,
- The utilities should update their proposals to include the following such that the CPUC and parties can independently verify whether these projects provide incremental benefits compared to related projects funded through existing programs:
    - A demonstration that the research is not duplicative,
    - Revised learning objectives that clearly articulate the specific objectives of each project, and metrics that provide a benchmark to determine project success on an ex-post basis,
    - Details on the "analysis of potential benefits and locational values associated with high-DER penetration," consistent with any updated direction from the CPUC,
    - Additional details regarding how the proposed demonstration site compares to the utility service territory generally such that the replicability of results can be evaluated,
    - Better definition of type, scale, and ownership of DER technologies to be used,
    - Better definition of the specific tasks to be performed as part of the project (e.g. write computer code, perform laboratory testing, install hardware, perform field testing on one feeder vs. an entire substation),
    - Better definition of the equipment (hardware and software) to be procured,
    - More detailed budget estimates consistent with the more detailed definitions of tasks and equipment, funding from other sources, and an estimate of DER procurement costs, where applicable,
    - A more detailed schedule consistent with the more detailed definitions of tasks and equipment, including key milestones, time for baseline measurements, and tasks and milestone for any related projects,

- Accurate representation of any requests for "wired alternatives" that could be deferred or avoided by the project.

ORA recommends that it may be appropriate for Demo D to be a "meta-project" that analyzes the results of EPIC and other projects and combines them into a single set of findings, rather than Demo D consisting of additional field demonstration projects.

Should the CPUC determine that these projects be evaluated in parallel with Demo C projects, SCE's proposed Demo D project should be considered for approval if the following are provided and vetted:

- Definition of learning objectives and tasks performed and how they are incremental to those of other projects including those funded through EPIC,
- DER procurement cost estimate, provided as a range,
- Schedule showing tasks and milestones for all active projects at the Johanna Jr. and Camden substations,

ORA does not recommend consideration of the SDG&E or PG&E Demo D proposals until updated proposals are provided.

E. ORA Preliminary Evaluation of Demo E Microgrid Projects

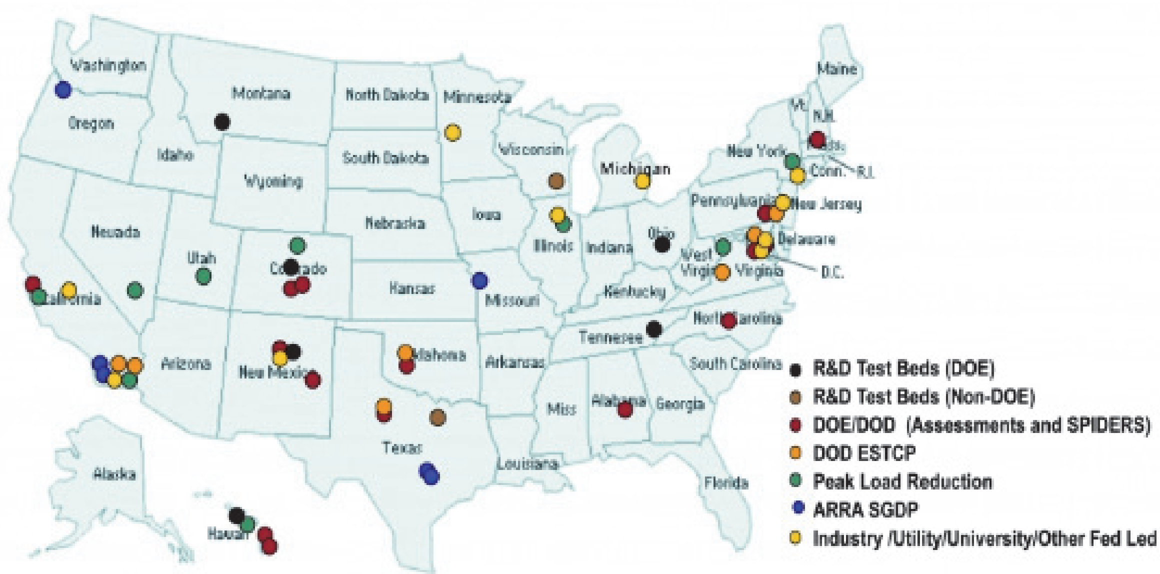
The CPUC provided guidance for Demo E projects to "demonstrate DER dispatch to meet reliability needs" and specified that the IOUs "develop a specification for a demonstration project" based on the following:[121]

- The Utility would serve as a distribution system operator of a microgrid where DERs serve a significant portion of customer load and reliability services.
- This project shall also explicitly seek to demonstrate the operations of multiple DERs as managed by a dedicated control system.
- The Utility shall explain how DER portfolios were constructed, as well as how they are being dispatched or otherwise managed.

[121] ACR DRP (Feb. 6, 2015), Attach., p. 7.

- This demonstration shall define necessary operational functionalities.
- This demonstration shall employ some quantity of third party DERs, and may include Utility-owned DERs.
- This demonstration project shall be scoped to commence no later than 1 year after Commission approval of the DRP.

Efforts to increase the deployment and commercialization of microgrids are not new to DRP. Microgrid RD&D projects are being performed nationwide:[122]



The projects shown in this map above represent many of the programs listed in section C above. Locally, microgrids have or will be operated at 14 campuses, military bases, jails and small communities in California.[123] The California EPIC program alone

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[122] http://energy.gov/oe/services/technology-development/smart-grid/role-microgrids-helping-advance-nation-s-energy-syst-0.

[123] http://microgridprojects.com/microgrid-projects-2/?Search=&Status=all&Location=california&Type=all&price_range_min=0&price_range_max=75000&order-by=featured&pageid=917. This is supported by the Success Stories section of report CEC-500-2015-071, p. 18. CEC Report CEC-500-2015-071 dated July 2015 is available at http://www.energy.ca.gov/2015publications/CEC-500-2015-071/CEC-500-2015-071.pdf.

currently has eight microgrid projects active with a total budget of $35.9 million including matching funds.[124] The EPIC project descriptions in the annual reports do not generally describe partnership or interaction with the local electric utility, so it is not clear whether any of these EPIC funded microgrids meet the requirement for utility control and operation of DER within the microgrid. Given the nationwide attention to microgrids, including funding for demonstration projects, it is imperative that utility proposals for Demo E microgrid projects clearly define their incremental learning objectives and explain how they will be attained. In addition, the utilities should explain why these approved project sites cannot be leveraged, potentially as Demo D host sites, to accelerate and reduce the cost of Demo E projects.

1. SDG&E's Demo E meets Guidance requirements, potentially without further funding.

SDG&E proposes to run its microgrid demonstration project in Borrego Springs, a location where it has operated a microgrid since 2010.[125] SDG&E has ongoing projects funded through the Department of Energy (DOE) and California Energy Commission (CEC) to expand the Borrego Springs microgrid and these projects will overlap with the Demo E proposed schedule.[126] While the funding requested through the DRP proceeding is relatively small, $500,000, this estimate does not include modifications to the microgrid that could be required.[127] These costs should be defined before this project is approved. More importantly, SDG&E should update all elements of its plan to define the incremental learning objectives and benefits of this DRP project compared to previously

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[124] Based on review of 2015 EPIC Annual report. This includes projects EPC-14-050, 053, 054, 055, 059, 060, 080, and 085. Project EPC-14-005 separately requests nearly $2 million to integrate advanced solar forecasting into grid operations, including at the UCSD microgrid. *See* Attachment 2.

[125] SDG&E presentation from the June 28, 2016 workshop, Slide 2. *Also see* final report on PIER funded Borrego Springs Microgrid Demonstration Project, CEC-500-2014-067 dated October 2013.

[126] SDG&E presentation from the June 28, 2016 workshop, Slides 6 and 10.

[127] Attachment 1 to SDG&E's June 17, 2016 filing. Refer to the second page of the Project E discussion in response to the May 17 Ruling question 7.

funded projects, and how achievement of these incremental objectives can be evaluated. The current goal and objectives for this proposed project, broken into specific requirements, mirror the CPUC guidance, but do not highlight what is unique about this project:[128]

- Serve as a distribution system operator of a microgrid,
- DER's serve a significant portion of the microgrid's load,
- Detail how multiple DERs are managed and operated,
- Explain how the DER portfolio was constructed as well as dispatched,
- Define necessary operational functionalities,
- Utilize the lessons learned from Demo E to develop a framework for microgrids throughout SDG&E service territory,

SDG&E's original microgrid project at Borrego Springs required the operation of multiple DERs in the microgrid, and the currently funded DOE and CEC projects appear to incorporate additional DERs.[129] This microgrid was able to support the community during a planned outage in May 2015.[130] It therefore appears that many of the proposed objectives for SDG&E's Project E have been largely met through prior projects and/or may be addressed in the scope of currently funded projects.

2. The need for PG&E's Demo E microgrid on Angel Island should assessed (1) in relation to the Blue Lake Rancheria renewable microgrid funded by EPIC, (2) in light of GRC funding authorizing recovery for the two undersea cables in the GRC and (3) relative to the total projected costs for the DER procured in the Angel Island microgram project.

PG&E's proposed project is located on Angel Island, a small island in the San Francisco Bay. PG&E' estimated cost for this project is $4.2 million plus the cost of

[128] Attachment 1 to SDG&E's June 17, 2016 filing. Refer to the first page of the Project E discussion in response to the May 17 Ruling questions 1 and 2.

[129] See CEC EPIC project EPC-14-060 description in Attachment 2.

[130] SDG&E presentation from the June 28, 2016 Demos C, D, and E workshop, Slide 8.

DER procurement.[131] PG&E does not describe how the infrastructure on Angel Island, the DER sites, and load profiles are consistent with other probable microgrid locations, so it is not possible to determine the replicability of this project. Instead, PG&E's primary rationale supporting this project is its ability to avoid, not just defer, replacing two 12 kV undersea cables that have historically served Angel Island.[132]

The issue of duplication of demonstration projects appears again for this project as PG&E is already a partner in a CEC EPIC funded microgrid titled "Demonstrating a Community Microgrid at the Blue Lake Rancheria." The project is scheduled from July 6, 2015 to March 30, 2018 with a total budget of $6,318,422 ($5,000,000 CEC EPIC funds and $1,318,422 matching funds). The project's goals appear to be consistent with the CPUC's Demo E project guidance:

- Demonstrate the ability of a community-scale microgrid to bolster the resiliency of an American Red Cross support facility.
- Demonstrate the capability of the microgrid to power itself with high penetration of local renewable resources.
- The microgrid will be designed to island indefinitely."[133]

Additionally, PG&E already requested money to replace the two 12kV cable in 2018.[134] This request was not opposed, so it is likely to be included in rate adjustments once a GRC decision is approved by the commission.[135] PG&E should provide a discussion of how funding approved in the GRC for cable replacement, assuming such

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[131] PG&E Demos C, D E Revised Proposal (Jul. 17, 2016), p. A-25.

[132]PG&E Demos C, D E Revised Proposal (Jul. 17, 2016), p. A-21.

[133] *See* CEC EPIC project EPC-14-054 description in Attachment 2.

[134] PG&E workpapers supporting Prepared Testimony on Electrical Distribution, Exhibit PG&E-4, in A.15-09-001, PG&E 2017 GRC, pp. WP 11-3 and WP 11-26. This request for funding in the GRC included a section on "Alternatives Considered" which does not discuss the option of operating a microgrid. WP 11-27.

[135] PG&E Rebuttal Testimony on Electrical Distribution, Exhibit PG&E-23, in A.15-09-001, PG&E 2017 GRC, pp. 11-3 to 11-8. Hearings in the GRC proceeding have been delayed until August 3, 2016 to allow PG&E and parties to engage in settlement discussions.

funding is approved, would be tracked and applied to the microgrid project. If this proposal is to be evaluated as a "deferral" project, there is insufficient data to perform a cost benefit study since PG&E's Demo D proposal does not detail what is included in the $4.2 million estimated cost, or the unquantified "DER procurement costs." The deferral value of this project can only be assessed if the cost of this system is known.

3. SCE's Demo E has sufficient technical learning objectives but fails to provide more than academic value from the operation of its microgrid in an area without need for additional reliability and resiliency.

SCE proposes to perform its Demo E in a suburban area of Irvine where a previous DOE Irvine Smart Grid Demonstration (ISGD) project was performed.[136] SCE requests $10.2 million for this project, excluding DER procurement costs, with no explicit leveraging of funding from other projects.

One of the strengths of SCE's proposal is that it provides some details about the technical learning objectives for the project, for example that it will test the ability to operate in island mode for any two hours, and that it will test protection schemes. While this is a step beyond the details provided by PG&E and SDG&E, it still only provides one testable hypothesis, and there is no discussion of results from other projects with similar hypotheses.[137]

Another apparent strength of SCE's showing is that it proposes to use an existing test site, which superficially should reduce costs and project duration, similar to SDG&E's Borrego Springs proposal. However in this case, the benefits are less obvious, as witnessed by the $10.2 million minimum cost estimate compared to SDG&E's for $0.5 million. This is due in part to the fact that the ISGD project did not include a

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[136] SCE Comments Proposing Demonstration Projects (Jul. 17, 2016), p. 38.

[137] The expected outcomes listed on Slide 9 of SCE's June 28, 2016 workshop presentation are similarly high level potential results, with no added detail of hurdles to microgrid implementation that will potentially overcome.

microgrid control system and that the project was "recently completed."[138] The potential for leveraging benefits from this location, therefore, appear to be limited.

One of the unique weaknesses of this project is that it does not appear to be located such that it serves a particular reliability need. A potential benefit of microgrids is added reliability and resiliency, and this assumes customers on the microgrid receive benefits that offset the additional costs of the microgrid. Nothing in SCE's proposal indicates that the 151 residential customers and one community center require more reliability or resiliency than SCE provides to its customers generally. The fact that SCE includes $850,000 for "maintenance and decommissioning" further suggests that the microgrid is not needed and that SCE does not intend to operate the system beyond this project. It does not appear that this location is representative of where microgrids would likely be deployed.

4. ORA findings regarding Demo E projects.

Many of the findings regarding Demo D projects are applicable to Demo E projects:

- Microgrids are the subject of numerous RD&D projects nationwide and in California,
- These Demo E project proposals do not include a demonstration that the research is not duplicative,
- The utility filings to date do not provide the sufficient detail to determine if they are duplicative or not, limited information has been provided to show that results from the demonstration projects are replicable,
- Funding for wired alternatives has been requested in PG&E's GRC which should be factored into demonstration project E funding authorization.

ORA also found that both the CPUC and CEC previously investigated microgrids but this work is neither referenced nor incorporated into the utility plans. A 2014 white paper from the CPUC's Policy and Planning Division (PPD) and ED discusses the

[138] SCE Comments Proposing Demonstration Projects (Jul. 17, 2016), p. 39.

potential benefits of microgrids as well as challenges to microgrid development that must be overcome if they are to be widely adopted.[139] Microgrids are also being considered by the CEC. The 2015 report "Microgrid Assessments and Recommendations to Guide Future Investments" identified barriers to deployment and commercialization of microgrids and recommendations to help guide future RD&D investment.[140] The CEC is also developing a roadmap to support commercialization of microgrids.[141]

Finally, the potential benefits of microgrids — including increased reliability, resilience, and security — appear to be supported by deployments to date at military bases, jails, university campuses, and remote communities. The CPUC report's finding that "location matters!" highlights that microgrids will serve a limited set of customers for whom the added cost of the microgrid is balanced by the added benefits.[142]

5. *ORA recommendations regarding Demo E projects*

ORA's general recommendations for Demo E microgrid projects are the same as for Demo D except for the following:

- The CPUC and utilities should focus on Demos A, B and C and schedule evaluation of microgrid projects in a later phase of the DRP. This is particularly true of microgrids given that any potential benefits will likely accrue to a smaller set of customers than for the other projects.
- Updates to the utility proposals should include all the items discussed for Demo D projects, and:
  - Explain how the projects address the barriers to commercialization identified in the CPUC and CEC reports cited in the previous section,

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[139] "Microgrids: A Regulatory Perspective," Villarreal and Erickson, Apr. 14, 2014.

[140] CEC Report CEC-500-2015-071 (Jul. 2015), available at http://www.energy.ca.gov/2015publications/CEC-500-2015-071/CEC-500-2015-071.pdf

[141] Joint Energy Agency Workshop to Kick-Off the Development of a Roadmap to Commercialize Microgrids in California (May 24, 2016), available at http://www.energy.ca.gov/research/notices/#05242016.

[142] CPUC Whitepaper *"Microgrids: A Regulatory Perspective," Villarreal and Erickson, Apr. 14, 2014*, p. 23.

- Incorporate any developments in the CEC microgrid roadmap cited in the previous section,

Should the CPUC determine that these projects be evaluated in parallel with Demo C projects, ORA would recommend the following based on the information currently available:

- SDG&E's proposed Demo E project should be considered for approval if the following are provided and vetted:
  - Definition of learning objectives and tasks performed and how they are incremental to those of other projects including those funded through EPIC,
  - Identification of barriers to microgrid deployment and commercialization that will be address by this project,
  - Schedule showing tasks and milestones for all active projects at Borrego Springs,
  - An integrated budget, including DRP, EPIC, and all active programs active at Borrego Springs, with sufficient details to allow reviewers to understand the products and services funded by each program,
- PG&E's proposed Demo E project should be considered for approval only if the following are provided and vetted:
  - A complete cost and benefit analysis is provided comparing the proposed microgrid project to the conductor replacement project included in the 2017 GRC,
  - The quantified net benefits from the deferral value of the project and non-quantified benefits as a DRP demonstration project combines to support the reasonableness of the project,

A cost recovery mechanism is proposed that accounts for PG&E's request in the 2017 GRC, and whether it is funded,

- SCE's proposed Demo E project should <u>not</u> be considered for approval based on the following:
  - The project does not leverage any other funding sources,

- The location is not a natural candidate for a microgrid as customers do not need additional reliability or other potential benefits of microgrids,

The need for a Demo E project within each utility service area has not been shown.

F. ORA recommends bifurcation of Demo from Demo D and E and suggests consideration of Demo C first

ORA supports Commission review of Demo C prior to consideration of Demo D and E. Demo C is directly related to meeting the objectives of the DRP because it tests the ability of DERs to provide the locational value calculated in the LNBA and this type of learning is not otherwise funded. Demos D and E, on the other hand, have objectives which overlap with existing RD&D projects such as EPIC and the DOE ARRA programs. IOUs are already implementing projects similar in scope to Demo D and E. Therefore, prioritization of Demo C does not delay Demo D and E implementation as a practical matter. Also, ORA requires further review of Demo D and E to assess the incrementality of learning objectives compared to related RD&D funded projects cited in Sections C, D, & E.

III. CONCLUSION

ORA respectfully requests the Commission adopt ORA's recommendations, as discussed herein.

Respectfully submitted,

/s/ Matt Miley

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